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Advanced Reservoir Characterization and Horizontal Laterals
in a Class I Reservoir – East Binger (Marchand) Unit”**

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Abstract

Work associated with Budget Period 1 of the East Binger (Marchand) Unit project is nearing completion. A major aspect of this project is accurate modeling of the performance of horizontal wells. Well EBU 37-3H, the first horizontal well drilled in the unit, was drilled in the second quarter of 2001. After much difficulty establishing economic production from the well, the well was hydraulically fractured in November 2001. Post-treatment production has been very encouraging and is significantly better than a vertical well drilled in a similar setting.

International Reservoir Technologies, Inc. has completed the final history match of the pilot area reservoir simulation model, including tuning to the performance of the horizontal well. The model's predicted reservoir pressure gradient between injection and production wells accurately matches observed data from the field, a significant improvement from prior model predictions. The model's predicted gas injection profiles now also more accurately match field data.

Work has begun toward evaluating the optimum development scenario with the pilot model. Initially, four scenarios will be evaluated – two involving all horizontal infill wells, one involving all vertical infill wells, and one involving a combination of vertical and horizontal infill wells. The model cases for these scenarios have been defined, and construction of them is underway

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Introduction

Work associated with Budget Period 1 is nearing completion. Evaluation of future development scenarios for the East Binger (Marchand) Unit is under way.

A major aspect of this evaluation is accurate modeling of the performance of horizontal wells. Well EBU 37-3H, the first horizontal well drilled in the unit, was drilled in the second quarter of 2001. The well was hydraulically fractured in November 2001. Post-treatment production has been very encouraging and is significantly better than a vertical well drilled in a similar setting.

The pilot area reservoir simulation model history match has been finalized. Significant improvements have been made to the match. Initial forecast cases have been defined, and construction of them is underway.

Executive Summary

Work associated with Budget Period 1 is nearing completion.

Well EBU 37-3H, the first horizontal well drilled in the East Binger Unit, was drilled in the second quarter of 2001. After much difficulty establishing economic production from the well, the well was hydraulically fractured in November 2001. Post-treatment production has been very encouraging and is significantly better than a vertical well drilled in a similar setting.

International Reservoir Technologies, Inc. has completed the final history match of the pilot area reservoir simulation model, including tuning to the performance of the horizontal well. The model's predicted reservoir pressure gradient between injection and production wells accurately matches observed data from the field, a significant improvement from prior model predictions. The model's predicted gas injection profiles now also more accurately match field data.

Work has begun toward evaluating the optimal development scenario with the pilot model. Initially, four scenarios will be evaluated – two involving all horizontal infill wells, one involving all vertical infill wells, and one involving a combination of vertical and horizontal infill wells. The model cases for these scenarios have been defined, and construction of them is underway.

Results and Discussion

The following is a detailed review of the work conducted in this reporting period.

Task 1.1.2 – Reservoir Data Collection

Calibration of Horizontal Productivity

One of the major items planned within this task is the calibration of horizontal performance in the reservoir simulation model to actual field performance. As previously reported, horizontal well EBU 37-3H was drilled during the second quarter of 2001. Most of the work of the third quarter and first half of the fourth quarter was focused on the completion of this well.

Figure 1 is a wellbore diagram of well 37-3H. The external casing packer at the bottom of the liner failed, allowing cement to escape about 250' past the liner shoe into the open hole. After drilling this out and washing the horizontal section with gelled diesel, the well flowed 5-10 bopd and approximately 400 mcf/d. A gas sample was analyzed and found to contain 78% nitrogen. A pressure build-up test was conducted, and the interpretation was that the well was still damaged. This is discussed in more detail in the previous quarterly report.

In mid-October, the well was perforated open hole with through-tubing perforating guns in an attempt to get beyond any very shallow wellbore damage, while at the same time creating weak points in the rock structure for the initiation of a hydraulic fracture should one be conducted. Six sets of perforations were shot, each 16' long, with 2 shots per foot (spf) in 13' of the 16', and 6 spf in 3' in the middle of the interval. The intervals were spaced roughly 100' apart on average, as noted in Figure 1.

Production improved only slightly following the perforating, to 10-15 bopd and 560 – 630 mcf/d, with the nitrogen content of the produced gas about the same – 77%. A production log was run to determine the source of the gas production. It was found that most, if not all, of the gas was coming from beyond 10,300'. This ruled out the possibility that the gas was coming through a cement channel from overlying A and B sands or the upper part of the C Sand.

In early November, the well was hydraulically fractured. Approximately 78,500 pounds of 20/40 mesh intermediate strength proppant was placed into the formation. The proppant slurry was pumped at an average rate of 30 bbls/min and an average pressure of 4500 psi. The well's production improved to over 200 bopd and 2500 mcf/d initially. After two months, at the time of this report, oil production has declined to about 75 bopd, while the gas has remained steady at about 2500 mcf/d. Flowing tubing pressure has declined from over 2500 psi initially to about 1000 psi at last report. This has been controlled by the gradual opening of the surface choke. The nitrogen content of the produced gas has

declined from about 71% in the first few days after the fracture treatment to about 67% at last measurement.

The early post-frac performance of this well compares very favorably with the post-frac performance of a vertical well drilled in a similar setting. Well 66-2 was drilled in 1996 as a replacement well for an abandoned injection well. Figure 2 shows the location of this well. As evident in Figure 2, both 37-3H and 66-2 were drilled in thick pay (60'+) and in the vicinity of abandoned injection wells – 37G-1 and 66G-1, respectively.

Figure 3 shows the early post-frac production data for 37-3H and 66-2. Within two months of the fracture treatment, well 66-2's production was less than 50 bopd and 500 mcf/d. After two months, well 37-3H's oil production is 50% higher than 66-2's, and its gas rate is about five times higher.

Task 1.1.5 – Build Pilot Area Model

With significant production established in horizontal well EBU 37-3H, work resumed on the pilot area model. Significant improvement was made in the match between the model's predicted reservoir pressures and pressures measured in the field. Additional work was also done on the reservoir description and completion definitions to improve the matches of injection profiles for wells in this area.

The model's predicted average reservoir pressure has been close to calculated average field pressures for some time. However, as discussed in quarterly reports 15121R03 and 15121R06, the pressure gradient between injectors and producers is much steeper in the field (average pressure drop of 2900 psi) than previously predicted by the model (average pressure drop of 1300 psi). A series of adjustments to the model improved this match dramatically.

First, a correction was made in the model to the separation conditions operated in the field. This correction caused the model to over-predict gas production and under-predict oil production. Subsequent adjustments to the relative permeability data resulted in both the predicted oil and gas production volumes coming back in line with actual field data and a significant improvement to the pressure match. For wells in the focus area, the model's predicted average pressure drop between injectors and producers matches the measured average pressure drop of 3100 psi (this value is slightly different than the 2900 psi mentioned above due to acquiring additional data). See Figure 4.

Figures 5, 6, and 7 show the improvements made in the model's predicted injection profiles compared to actual measured profiles for three injection wells in the focus area: 38G-1, 45G-1, and 46G-1. One aspect of improving these matches was modifying the description of the A and B Sands that lie above the C Sand. The original description of these sands had many isolated, discontinuous sand bodies, as shown in Figure 8; hence, the model predicted little gas going into these sands. The new description, shown in

Figure 9, has much more continuity, allowing the wells in the model to inject and produce more fluid from this interval, as the actual profiles from the field indicate they do.

Task 1.1.6 – Evaluate Horizontal Lateral Performance or Other Development Design

It now appears that future horizontal wells will most likely be drilled as new wells, instead of lateral sidetracks of existing wells. This is a result of primarily two factors.

First, further investigation of wellbore configurations has led to the realization that there will not be significant cost savings in drilling lateral sidetracks. Drilling rates of penetration in the East Binger Unit (EBU) slow substantially below about 7500' TVD, and most of the cost of the drilling a new well occurs after reaching 7500' TVD. Many of the potential sidetrack candidates would require kicking off at or above 8000'. With the cost of abandoning the lower portion of the original hole, and the lost value of that wellbore as a vertical injection or production well, there does not appear to be much cost saving in sidetracking this type of well.

Second, the EBU has lost a number of wellbores due to casing corrosion over the life of the field. While most of these failures have been below the depth of probable sidetrack kickoff points, some have been shallower. One contributing factor to these failures appears to be a poor primary cement job. The increased likelihood of a casing problem with an existing well, compared to a new well, adds significant risk of losing the investment associated with drilling a horizontal sidetrack from an existing wellbore.

Initial development alternatives will thus all contain new horizontal wells in the model. Four development scenarios will be investigated with the pilot-area model:

- 1) drill horizontal producers and horizontal injectors in a pattern flood configuration;
- 2) drill horizontal producers and horizontal injectors in a peripheral flood configuration;
- 3) drill vertical producers and vertical injectors in a pattern flood configuration; and
- 4) drill horizontal producers and vertical injectors in a pattern flood configuration.

The pattern configuration of scenarios 1, 3, and 4 will be a line drive, based on observed flow patterns in the field. The peripheral configuration of scenario 2 will involve placing injection wells in the thin peripheral areas of the reservoir and producing wells in the thick central portion of the reservoir. In all cases involving horizontal wells, horizontal producing wells will be placed near the bottom of the reservoir, and horizontal injection wells will be placed near the top. All four scenarios will also involve converting some existing producing wells to injection, with the specific wells varying depending on the scenario. The forecasting of these cases with the pilot model was underway at the time of this report.

Conclusion

Work associated with Budget Period 1 is nearing completion. After much difficulty establishing economic production from EBU 37-3H, the first horizontal well drilled in the East Binger Unit, the well was hydraulically fractured in November 2001. Post-treatment production has been very encouraging and is significantly better than a vertical well drilled in a similar setting.

The pilot area reservoir simulation model history match has been finalized. Significant improvements have been made to the match between the model's predicted pressures and injection profiles and observed field data.

Initial forecast cases for evaluating the optimal development scenario for the unit have been defined, and construction of them is underway.

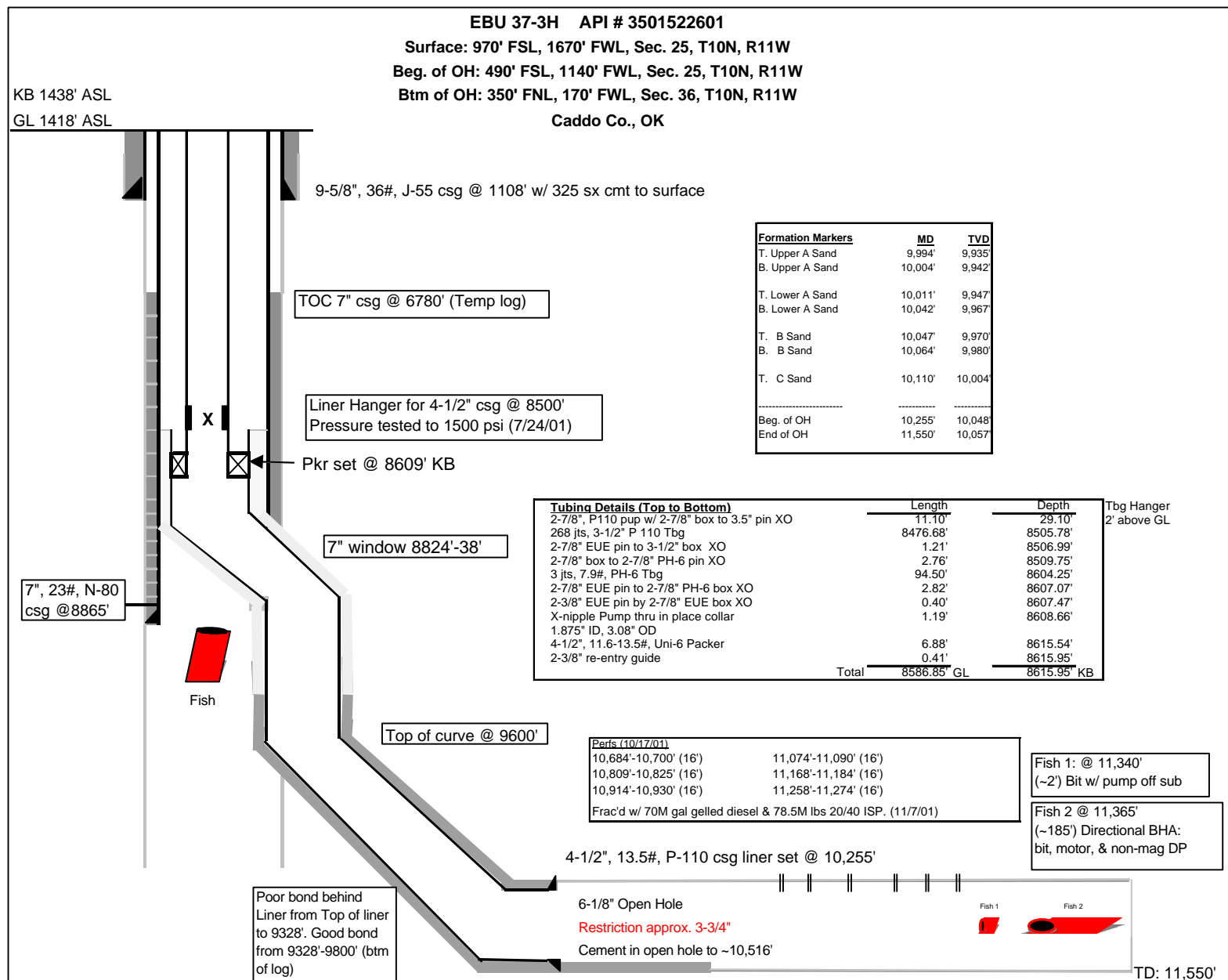


Figure 1. Wellbore schematic for EBU 37-3H.

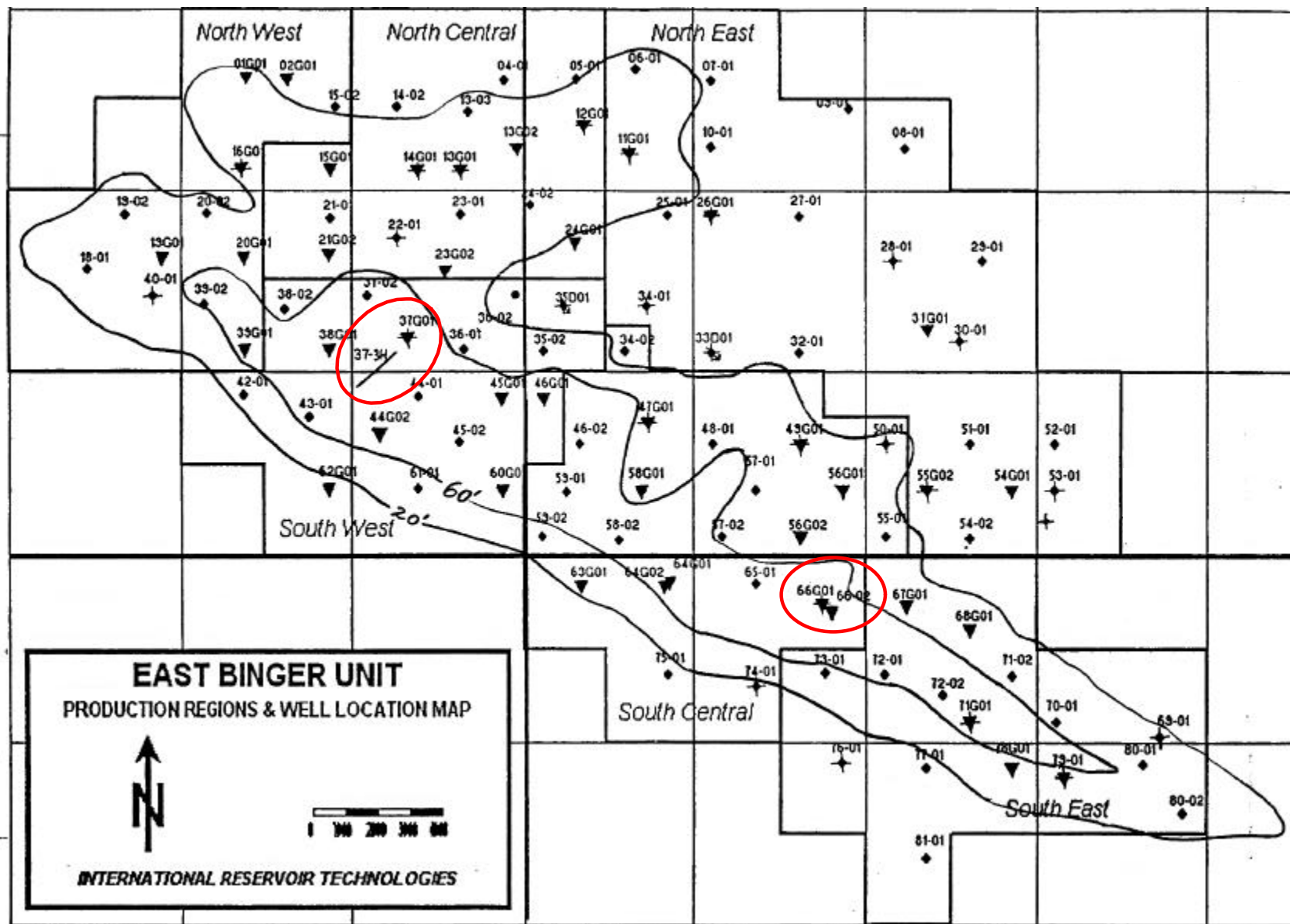


Figure 2. East Binger Unit field map. Note proximity of wells 66-2 and 37-3H to abandoned injection wells 66G-1 and 37G-1.

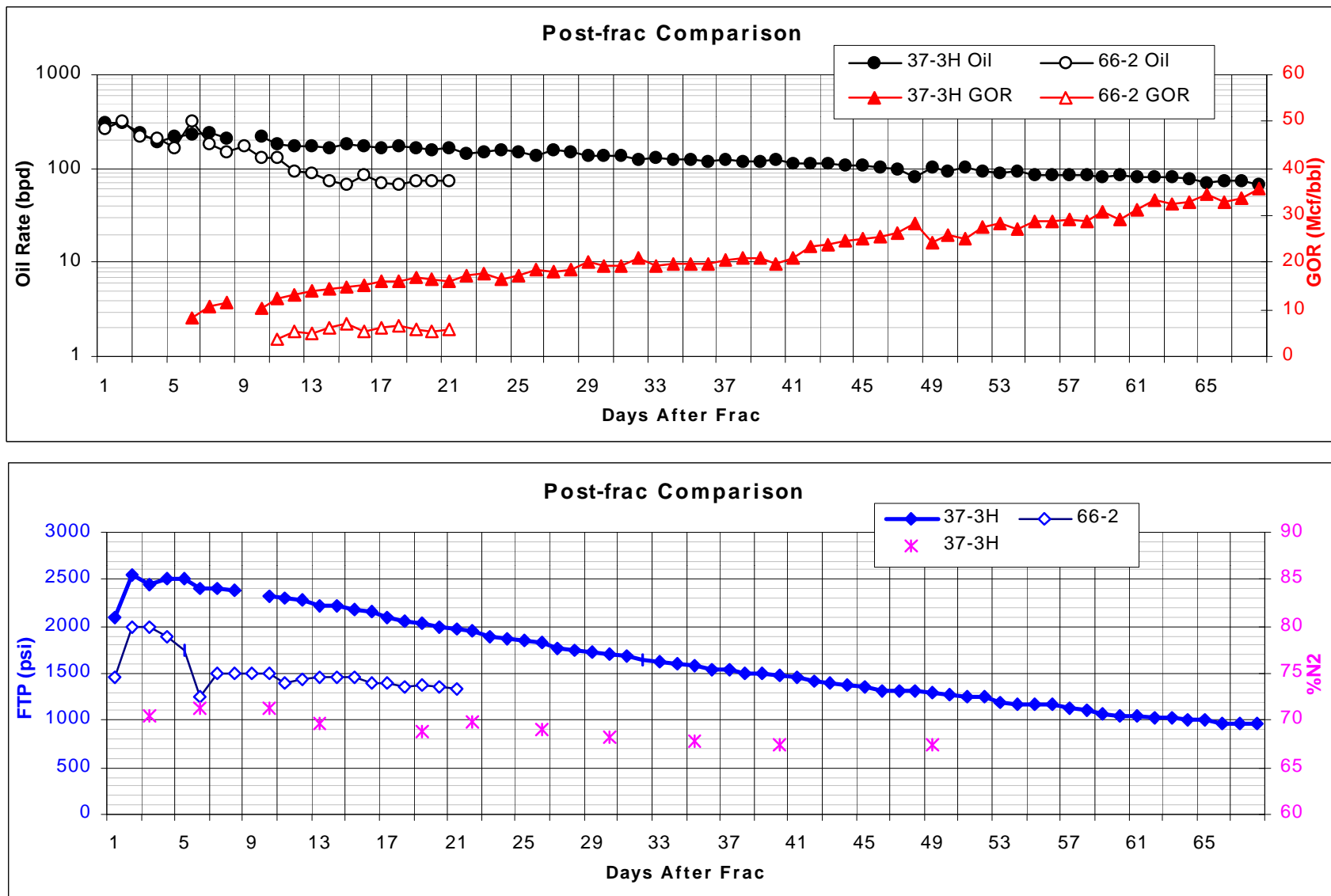


Figure 3. Post-frac performance of wells 37-3H and 66-2.

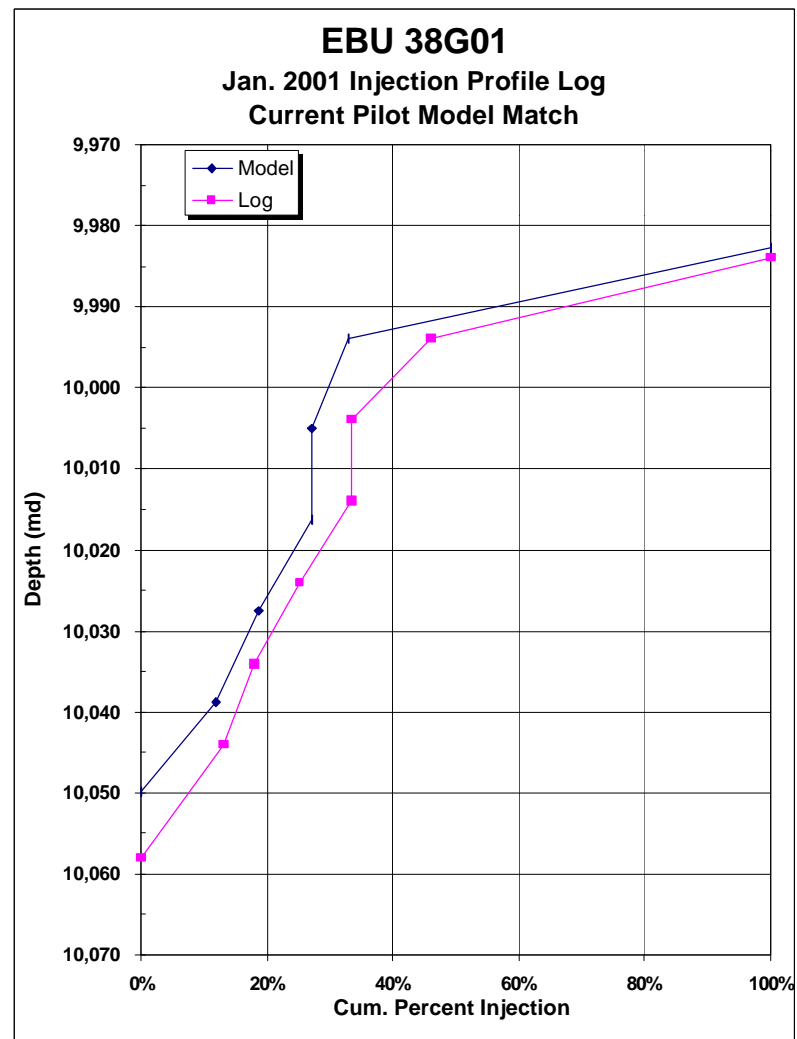
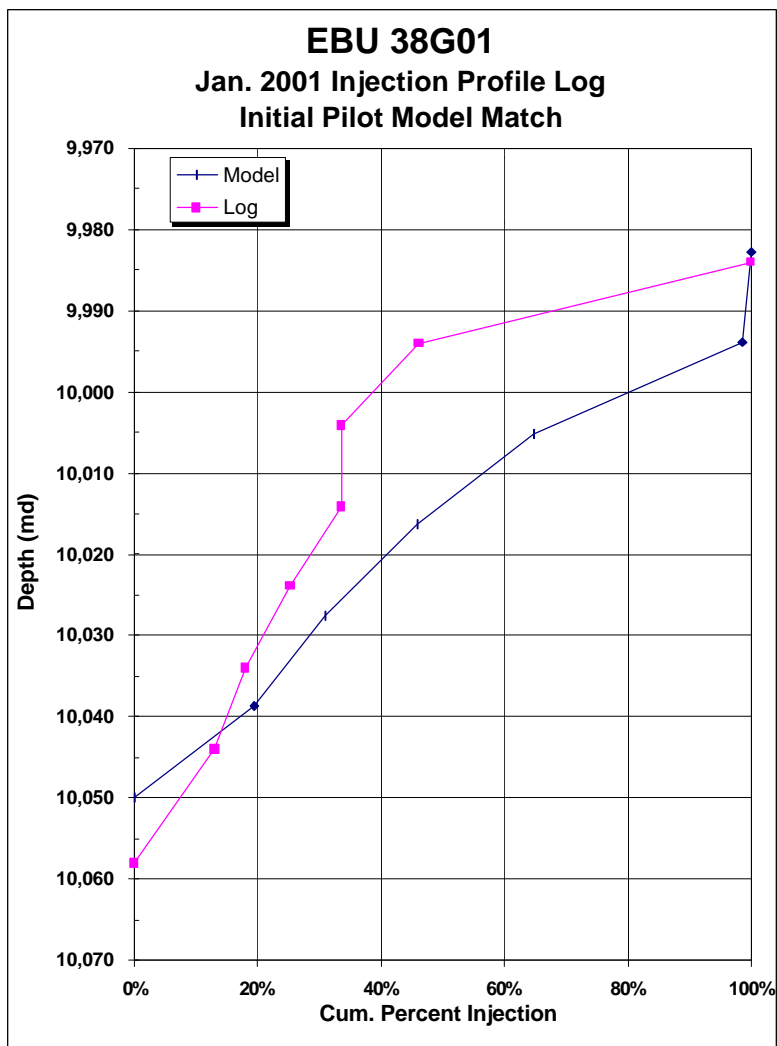


Figure 5. Comparison of model-predicted injection profile and field data for well 38G-1, before and after recent modifications to the model.

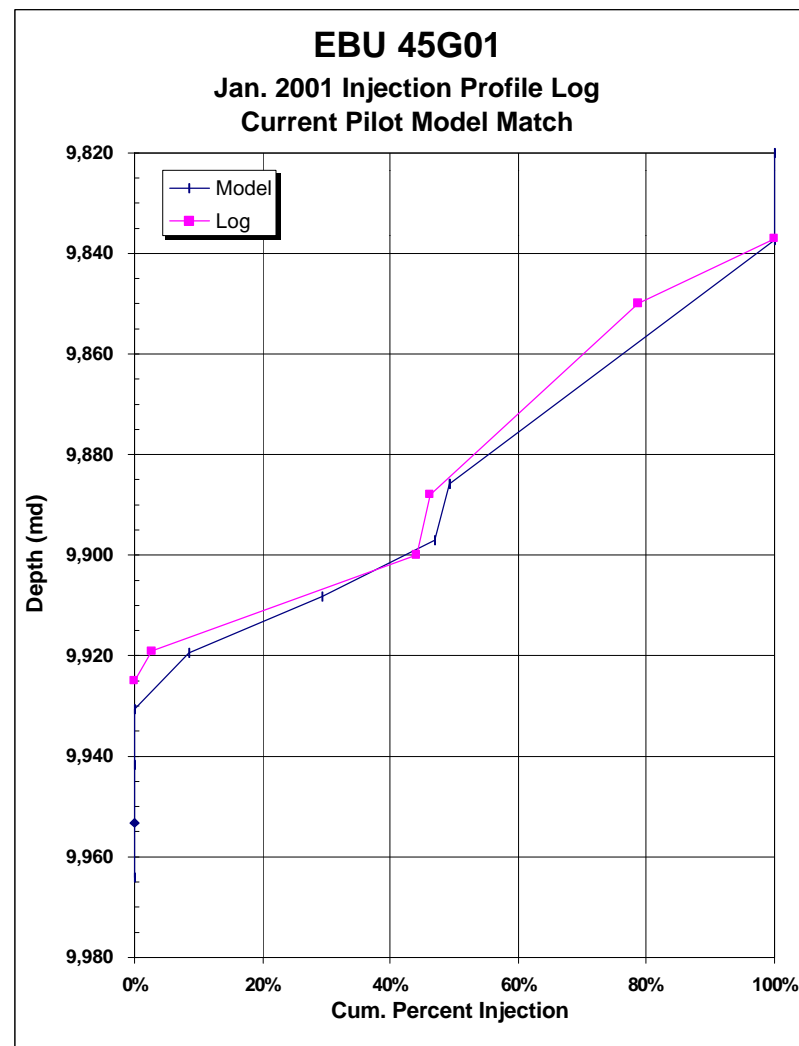
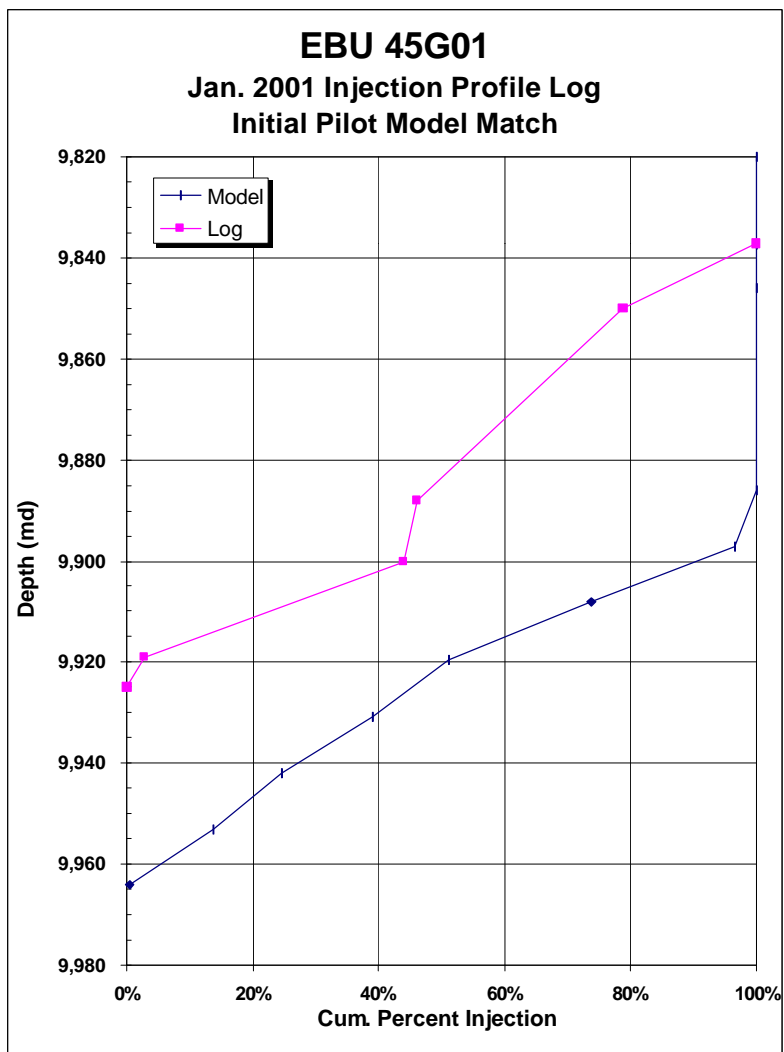


Figure 6. Comparison of model-predicted injection profile and field data for well 45G-1, before and after recent modifications to the model.

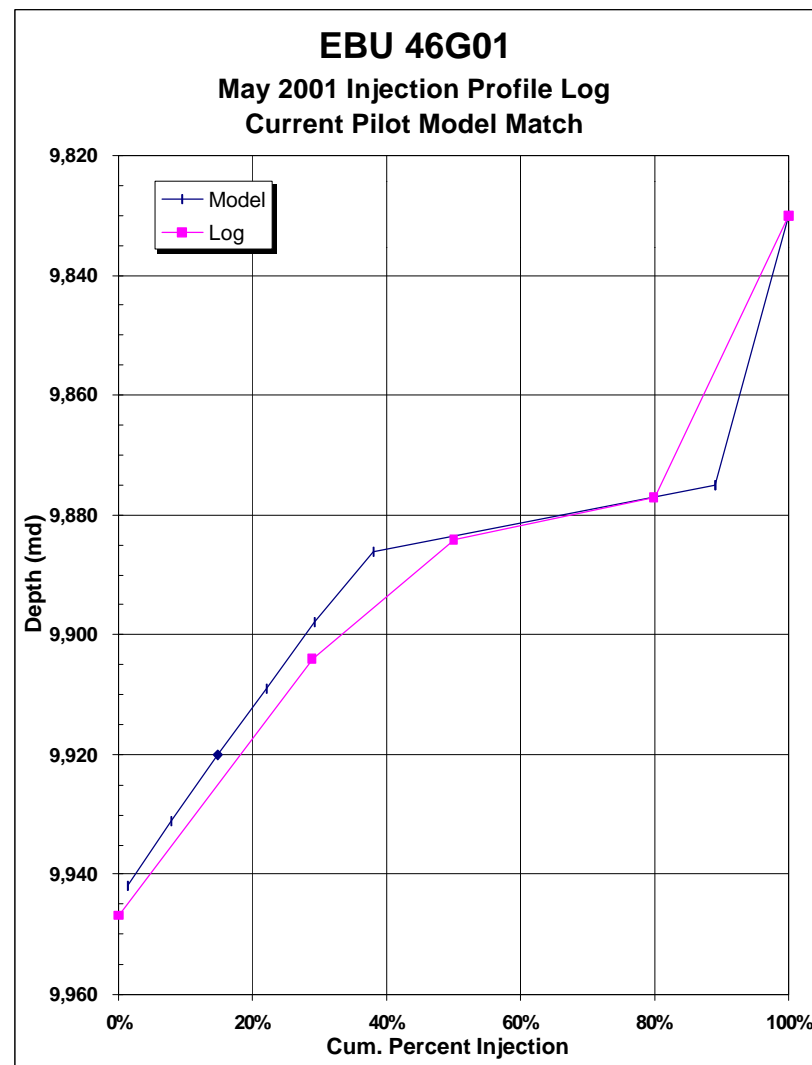
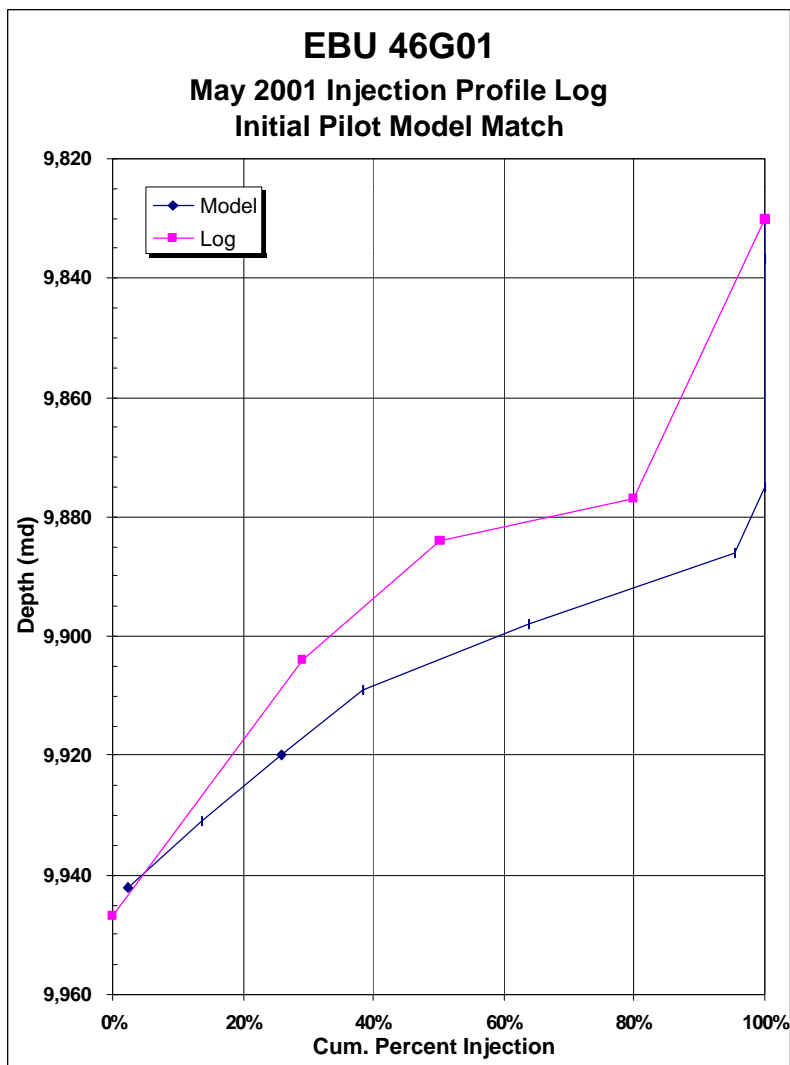


Figure 7. Comparison of model-predicted injection profile and field data for well 46G-1, before and after recent modifications to the model.

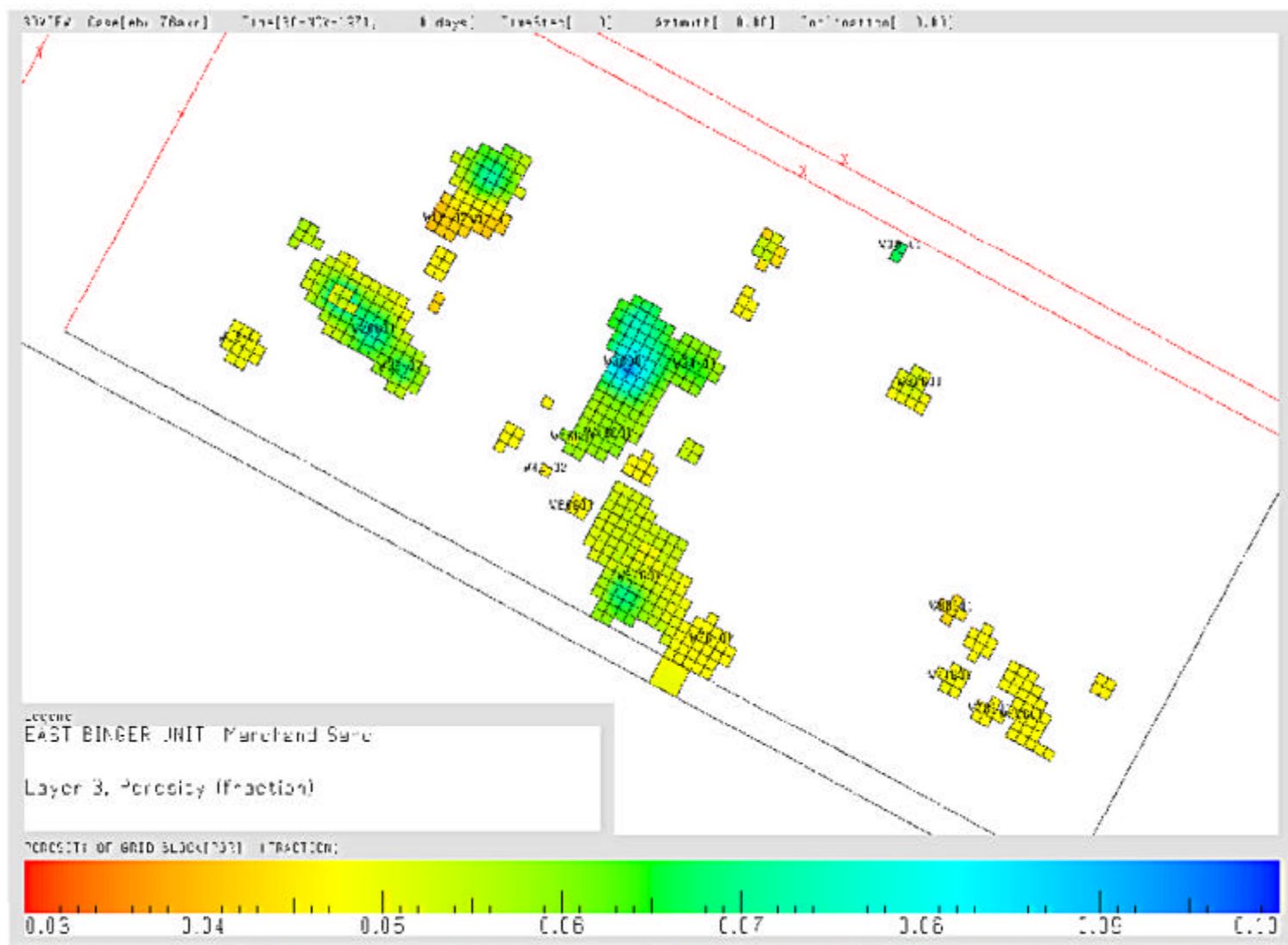


Figure 8. Map of upper sand from original simulation model – based on geologic model. Note discontinuity of sand.

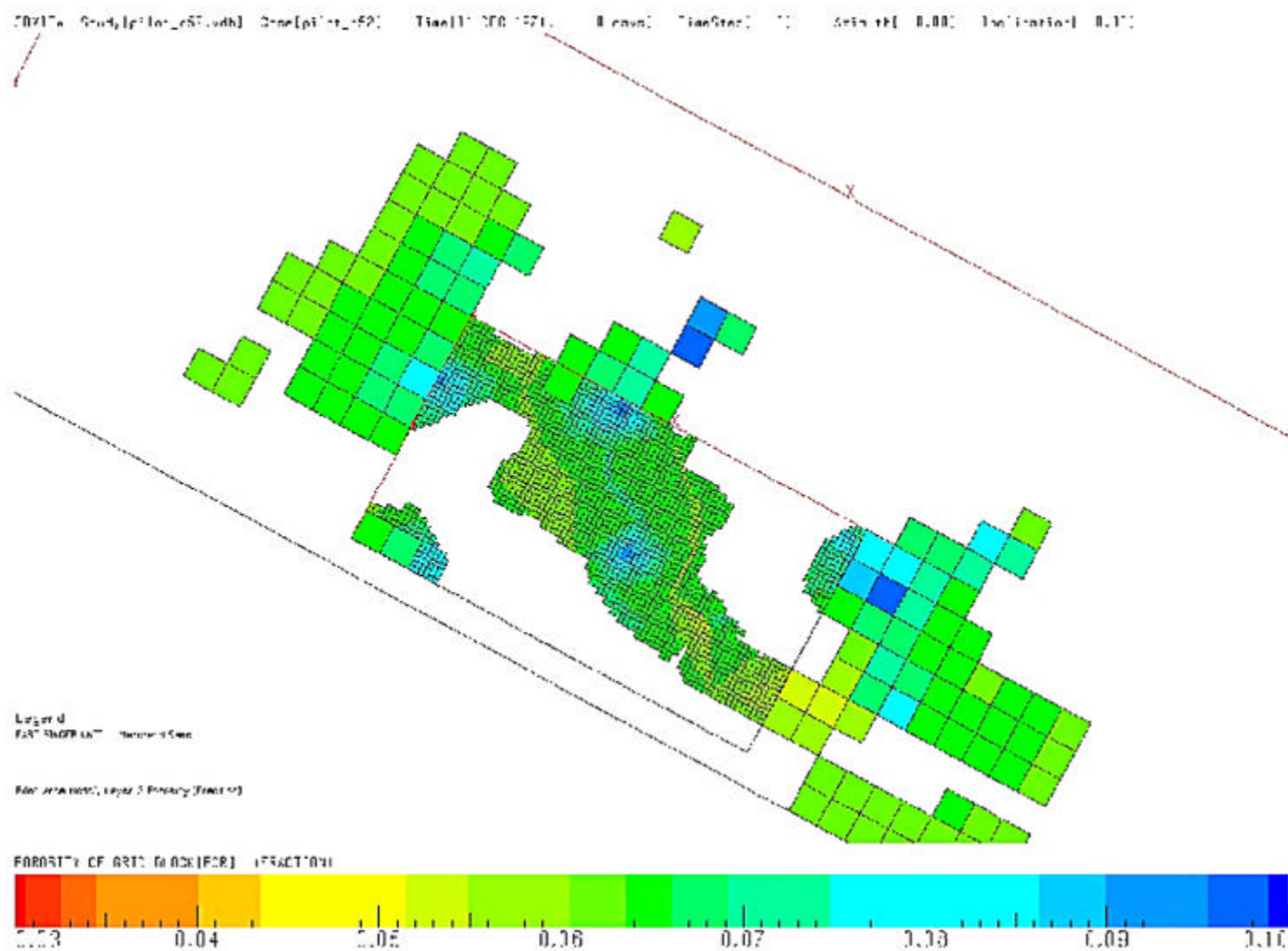


Figure 9. Map of upper sand in current simulation model. Sand is now continuous through central part of the model.